Results, Trends, and Insights from the Accident Sequence Precursor (ASP) Program

This attachment discusses the results of accident sequence precursor (ASP) analyses conducted by the U.S. Nuclear Regulatory Commission (NRC), as they relate to events that occurred during Fiscal Year (FY) 2001–2005. Based on those results, this document also discusses the NRC's analysis of historical ASP trends, and the evaluation of the related insights. The 13 tables and 18 figures that augment this discussion appear at the end of this attachment.

1.0 ASP Event Analyses

Table 1 summarizes the status of the NRC's ASP analyses, as of September 30, 2005. Specifically, the table identifies ASP analyses that the NRC staff has completed for events that occurred during FY 2001–2005. (Note that, as of September 30, 2005, the staff had not yet screened all of the FY 2005 events.) The following subsections summarize the results of these analyses, which are further detailed in the associated Tables 2–10.

FY 2001 analyses. The ASP analyses for FY 2001 identified 22 precursors. Of those 22 precursors, 17 were identified on the basis of final analyses, and 5 are expected to be precursors because they relate to events that involved cracking of the control rod drive mechanism (CRDM) housing.[1] All 22 of these precursors occurred while these plants were at power.

Table 2 presents the results of the staff's ASP analyses for FY 2001 precursors that involved initiating events, while Table 3 presents the analysis results for precursors that involved degraded conditions. In addition, Table 4 lists the CRDM cracking events that occurred during FY 2001–2003.

FY 2002 analyses. The ASP analyses for FY 2002 identified 14 precursors. Of those 14 precursors, 10 were identified on the basis of final analyses and 4 are potential precursors (expected to be precursors) because they relate to CRDM cracking events. All 14 of these precursors occurred while these plants were at power.

The staff has completed the final analysis of the multiple degraded conditions that occurred at the Davis-Besse Nuclear Power Station coincident with degradation of the reactor pressure vessel (RPV) head. This event is a *significant* precursor.[2]

Table 5 shows that there were no FY 2002 precursors that involved initiating events, while Table 6 presents the analysis results for precursors that involved degraded conditions. In addition, as previously noted, Table 4 includes CRDM cracking events that occurred during FY 2002.

FY 2003 analyses. The ASP analyses for FY 2003 identified 22 precursors. Of those 22 precursors, 21 were identified on the basis of final analyses and 1 is a potential precursor (expected to be a precursor) because it relates to a CRDM cracking event. All but one of the 22 precursors occurred while these plants were at power.

Table 7 presents the results of the staff's ASP analyses for FY 2003 precursors that involved initiating events, while Table 8 presents the analysis results for precursors that involved degraded conditions.

FY 2004 analyses. In January 2005, the NRC staff completed its screening and review of licensee event reports (LERs) concerning events that occurred during FY 2004. On the basis of that review, the ASP analyses have identified 16 precursors, including 6 based on final analyses and 10 based on preliminary analyses. Of the 16 precursors, 14 occurred while these plants were at power.

Table 9 presents the results of the staff's ASP analyses for FY 2004 precursors that involved initiating events, while Table 10 presents the analysis results for precursors that involved degraded conditions. The staff may identify additional precursors after completing the ongoing analyses of FY 2004 events in November of 2005.

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1 As of September 30, 2005, the staff has not completed its ASP analyses of CRDM cracking events that occurred during FY 2001–2003. However, based on scoping analyses completed to date, the staff anticipates that these events will yield an increase in core damage probability (ΔCDP) that is between 1×10^{-6} and 1×10^{-3}.

2 A *significant* precursor has a conditional core damage probability (CCDP) or increase in core damage probability (ΔCDP) that is greater than or equal to 1×10^{-3}.

FY 2005 analyses. The staff has completed all screening and reviews for potential *significant* precursors through September 30, 2005. In particular, the staff reviewed a combination of LERs and daily event notification reports (as required by Title 10, Section 50.72, of the *Code of Federal Regulations*, 10 CFR 50.72) to identify potential *significant* precursors. The staff is still screening and reviewing LERs concerning other potential precursor events that occurred during FY 2005.[3] Our goal is to complete preliminary assessments of all FY 2005 events by April 2006.

2.0 Industry Trends

This section discusses the results of trending analyses for all precursors and for precursors grouped by the order of magnitude of their CCDPs or **)**CDPs (called CCDP bins).

Statistically significant trend. The trending method used in this analysis is consistent with those methods used in the staff's risk studies. (See Appendix E of Reference 1.) The trending method uses the p-value approach for determining the probability of observing a trend as a result of chance alone. A trend is considered statistically significant if the p-value is smaller than 0.05. The p-value is shown for each trend in the figures provided at the end of this attachment.

Data coverage. Most of the data used in the trending analyses span the period from FY 1993 through FY 2004. The trends include the results of both final and preliminary analyses of potential precursors. However, the following exceptions apply to the data coverage of the trending analyses:

- *Significant precursors (10^{-3} bin).* The trend of *significant* precursors (i.e., CCDP or **)**CDP $\geq 1\times10^{-3}$) includes events that occurred during FY 2005. The results for FY 2005 are based on the staff's screening and review of a combination of LERs and daily event notification reports (10 CFR 50.72).[4] The staff analyzes all potential *significant* precursors immediately.

- *CRDM cracking events.* The staff is currently in the process of conducting its preliminary analyses of cracking that occurred in CRDM housings during FY 2001–2003. Sensitivity analyses conducted to date show that these cracking events are most likely potential precursors, but not *significant* precursors. Therefore, the staff has included these events in the total count and trending of all precursors (i.e., CCDP or **)**CDP $\geq 1\times10^{-6}$). For the purposes of CCDP bin trend analyses, these events were placed in the 10^{-5} CCDP bin.

2.1 Occurrence Rate of All Precursors

The NRC's Industry Trends Program (ITP) provides the basis for addressing the agency's performance goal measure on the number of "statistically significant adverse industry trends in safety performance" (one measure associated with the Safety Goal established in the NRC's Strategic Plan). Precursors identified by the ASP Program are one indicator used by the ITP to assess industry performance.

Results. No statistically significant trend is detected in the occurrence rate for all precursors that occurred during the period from 1993 through 2004. Figure 1 depicts the occurrence rate for all precursors by fiscal year. Section 2.3 provides a more detailed discussion of the relatively low number of precursors between FY 1997 and FY 1999 and the increasing number of potential precursors from FY 2000 through FY 2004.

2.2 Occurrence Rate of Precursors by CCDP Bin

In addition to the rate of occurrence of all precursors, the staff analyzed the data to determine whether trends exist in the rate of occurrence of precursors with CCDPs of different orders of magnitude. The method used in this analysis is based on a staff technical paper presented at the International Topical Meeting on Probabilistic Safety Assessment. (See Reference 2.)

Figure 2a is a histogram displaying the number of precursors per fiscal year for the CCDP $\$10^{-3}$ bin. (Note that Figure 2a shows the number of precursors instead of the occurrence rate.) This figure does not show a trend line because the staff did not detect a statistically significant trend.

By contrast, Figures 2b–d are histograms of the occurrence rate as a function of fiscal year for the other three CCDP bins (10^{-4}, 10^{-5}, and 10^{-6}). Because Figures 2b (10^{-4}) and 2d (10^{-6}) represent

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[3] Licensees have 60-day grace period after an event or discovery of a degraded condition to submit an LER.

[4] The staff has completed all screening and reviews through September 30, 2005.

statistically significant trends, each figure shows the trend line of the mean occurrence rate, with the 90-percent confidence band indicated by error bars. There is no trend represented in Figure 2c (10^{-5}).

Results. The trending analysis of the four CCDP bins ($\geq 10^{-3}$, 10^{-4}, 10^{-5}, and 10^{-6}) yielded the following results for the period from FY 1993 through FY 2004:

CCDP Bin	Trend
CCDP \$$10^{-3}$	No statistically significant trend
10^{-3} > CCDP \$ 10^{-4}	Decreasing trend–statistically significant
10^{-4} > CCDP \$ 10^{-5}	No statistically significant trend
10^{-5} > CCDP \$ 10^{-6}	Increasing trend–statistically significant

No trend is detected in the $\geq 10^{-3}$ CCDP bin and a decreasing trend is observed for the 10^{-4} CCDP bin. In addition, the trend for *important* precursors is decreasing (Figure 3).[5] This decreasing trend indicates that the occurrence rate of higher risk precursors is decreasing. There is no statistically significant trend detected in the 10^{-5} bin.

An increasing trend is detected in the 10^{-6} bin. The increasing trend is due to the grid-related LOOP events caused by the August 14, 2003 Northeast Blackout (3 precursors) and an increase in the number of identified events due to changes in ASP screening criteria (20 precursors). A discussion regarding the apparent increase in precursors during the FY 1997–2004 period is presented in Section 2.3.

2.3 Precursor Trend Evaluation

The objective of the precursor trends evaluation is to investigate the apparent low number of precursors during FYs 1997, 1998, and 1999 and the subsequent increase during FY 2000–2004.

Factors that may contribute or influence the increasing trend in the occurrence rate of all precursors during FY 1997–2004 were investigated in this evaluation. In addition, trending analysis was performed on precursor data in FY 2001–2004.

Results, insights, and conclusions from this evaluation are summarized below.

Trending Analysis Results (FY 1997–2004). Statistical tests were performed on precursor data to identify influences on trends from common groups of precursors during the FY 1997–2004 period. To ensure consistency in the data during the FY 1997–2004 period, the number of precursors in later years were normalized (i.e., rebaselined) in the statistical tests to account for the increase in scope of the ASP Program in FY 2001.

Rebaselining. To ensure consistency in the data during the 8-year period from FY 1997 through FY 2004, data in later years were adjusted to reflect the screening criteria that were used in the ASP Program prior to FY 2001 to select potential precursors for detailed analysis.

Analysis methods and Standardized Plant Analysis Risk (SPAR) models used in the ASP Program have evolved over time, resulting in increased capabilities to analyze complex conditions that were previously screened out during earlier years. Beginning around FY 2000 (at the end of calendar year 1999), all degraded conditions are considered for ASP analysis.

Examples of conditions that were screened out during the early years included potential initiators involving fire, external events (e.g., seismic and tornado), high-energy line breaks, and internal flooding.

In addition, current ASP Program screening criteria include all greater than Green inspection findings evaluated under the Significance Determination Process (SDP). Only LERs were screened prior to the full implementation of the Reactor Oversight Process (ROP) in April 2000.

Rebaselining removed 23 precursors from the data.

Precursor groups. The rebaselined precursor data were then tested to identify significant influence on trends caused by common groups of precursors, such as precursors with similar cause, similar initiator, or higher than average number of precursor from the same plant or site. Potential common groups of precursors that were identified

[5] An *important* precursor has a conditional core damage probability (CCDP) or increase in core damage probability ())CDP) that is greater than or equal to $1{\times}10^{-4}$.

during FY 1997–2004 are —

- grid-related LOOP events caused by the August 14, 2003 Northeast Blackout (8 precursors),
- all LOOP events, including grid-related LOOPs (22 precursors),
- CRDM housing cracking conditions (10 precursors)[6], and
- precursors at Oconee and D.C. Cook (22 precursors).

Results. A review of the trending results of the rebaselined data reveal the following:

- *Precursors $\$10^{-4}$.* No statistically significant trend is detected in the occurrence rate of the higher risk precursors with a CCDP or)CDP $\$1\times10^{-4}$ during FY 1997–2004.

- *Precursors $\$10^{-5}$.* A statistically significant increasing trend is detected in the occurrence rate for precursors with CCDP or)CDP $\$1\times10^{-5}$ during FY 1997–2004.

  No trend is detected if any or all of the following precursor groups are removed from the data: Northeast Blackout LOOP events, all LOOP events, or CRDM cracking conditions.

- *Precursors $\$10^{-6}$.* A statistically significant increasing trend is detected in the occurrence rate for precursors with CCDP or)CDP $\$1\times10^{-6}$ during FY 1997–2004, as shown in Figure 4a.

  No trend is detected if all LOOP events and CRDM cracking conditions are removed from the data, as shown in Figure 4b.[7]

  A further analysis of all precursors reveal the following:

  S *Degraded conditions, $\$10^{-6}$.* A statistically significant increasing trend is detected in the occurrence rate of precursors involving degraded conditions with a)CDP $\$1\times10^{-6}$ during FY 1997–2004.

  No trend is detected if the CRDM cracking conditions are removed from the data.

  S *Initiating events, $\$10^{-6}$.* A statistically significant increasing trend is detected in the occurrence rate of precursors involving initiating events with a CCDP $\$1\times10^{-6}$ during FY 1997–2004.

  No trend is detected if all LOOP events are removed from the data.

  S LOOP events had a greater influence on the increasing nature of the overall trend than CRDM cracking conditions.

- Other insights from the review of 1997–2004 data include the following:

  S One-half (50 percent) of the precursors involving degraded conditions had a condition start date prior to FY 1997 and are considered "legacy" conditions.

  Forty-five percent of degraded conditions that were discovered during FY 1997–2004 had a condition start date prior to FY 1993.

  S Over one-half (56 percent) of all "legacy" conditions that were discovered during FY 1997–2004 were discovered at two sites: Oconee (36 percent) and D.C. Cook (21 percent). Four "legacy" conditions involved all three units at Oconee and four "legacy" conditions involved both units at D.C. Cook.

  S LOOP events account for 21 percent of all precursors during FY 1997–2004, of which 36 percent were grid-related LOOP events caused by the Northeast Blackout.

Trending Analysis Results (FY 2001–2004). Trending analysis and statistical tests were performed on data during FY 2001–2004. This data set was not rebaselined for this evaluation.

The 2001–2004 period is of interest because FY 2001 is the first full year of the implementations of the Reactor Oversight Process (ROP) and the expanded scope of the ASP Program. In addition, the ASP Program started using Revision 3 of the SPAR models in the analyses of FY 2001 events. Therefore, the 2001–2004 data are consistent for trending purposes.

A review of the results reveals the following:

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6 The reviews and analyses for these events are ongoing.

7 Figures 4c and 4d show the trends for all rebaselined data excluding all LOOP events and CRDM housing cracking conditions separately.

- *Precursors ≥10^{-4}.* No statistically significant trend is detected in the occurrence rate of the higher risk precursors with a CCDP or ΔCDP ≥1×10^{-4} during FY 2001–2004. Four such precursors were identified during this period.

- *Precursors ≥10^{-5}.* No statistically significant trend is detected in the occurrence rate of all precursors with a CCDP or ΔCDP ≥1×10^{-5} during FY 2001–2004. Thirty-two precursors were identified during this period.

  - Precursors with a CCDP or ΔCDP ≥1×10^{-5} account for 43 percent of all precursors during FY 2001–2004.

  - A statistically significant increasing trend is detected in the occurrence rate of precursors involving only initiating events during FY 2001–2004.

    No trend is detected if either the Northeast Blackout LOOP events or all LOOP events are removed from the data.

  - No statistically significant trend is detected in the occurrence rate of precursors involving only degraded conditions during FY 2001–2004.

  - The removal of any of the following precursor groups does not have an effect on the trend of the occurrence rate of precursors with a CCDP or ΔCDP ≥1×10^{-5} during FY 2001–2004: grid-related LOOPs, all LOOP events, and CRDM cracking conditions.

- *Precursors ≥10^{-6}.* No statistically significant trend is detected in the occurrence rate of all precursors with a CCDP or ΔCDP ≥1×10^{-6} during FY 2001–2004, as shown in Figure 4e. Seventy-four precursors were identified during this period.

  - *All precursors ≥10^{-6}.* Loss of offsite power events account for 24 percent of all precursors during FY 2001–2004.

    When all LOOP events are excluded from the data, a statistically significant decreasing trend was detected.

  - *Degraded conditions ≥10^{-6}.* A statistically significant decreasing trend is detected in the occurrence rate of precursors involving degraded conditions with a ΔCDP ≥1×10^{-6} during FY 2001–2004.

  - *Initiating events ≥10^{-6}.* A statistically significant increasing trend is detected in the occurrence rate of precursors involving initiating events with a CCDP ≥1×10^{-6} during FY 2001–2004.

    Loss of offsite power events account for 18 of the 20 precursors involving initiating events during FY 2001–2004.

Trending Evaluation Conclusions. The following conclusions can be drawn from the evaluation of precursors during FY 1997–2004:

- *Important precursors.* No statistically significant trend is detected in the occurrence rate of risk-*important* precursors (i.e., CCDP or ΔCDP ≥1×10^{-4}) for either the FY 1997–2004 or FY 2001–2004 periods.

- *FY 1997–2004 trend.* A statistically significant increasing trend is detected in the occurrence rate of all precursors with CCDP or ΔCDP ≥1×10^{-6} during FY 1997–2004.

  No statistically significant trend is detected if initiating events involving LOOP events and degraded conditions involving cracking events in CRDM housings are removed from the data. Both precursor groups have a pronounced influence on the increasing trend. No underlying trend was found when LOOP events and CRDM cracking conditions are removed from the data set. The NRC is currently addressing the increasing number of LOOP events and the CRDM cracking events (information notices, Agency Action Plan, etc.).

- *FY 2001–2004 trend.* No statistically significant trend was detected in the occurrence rate of all precursors with a CCDP or ΔCDP ≥1×10^{-6} during FY 2001–2004.

  The trend of all precursors has a step increase from FY 1999 to FY 2000 and levels out after FY 2001.

- An increase in scope of the ASP Program resulted in the analysis and identification of 23 additional precursors that would not have been analyzed in during the FY 1997–1999 period.

  To ensure consistency between earlier and later data populations in the trending analysis, data should be rebaselined using consistent screening criteria applied to each year during the FY 1997–2004 period.

Data from FY 2001–2004 are consistent without having to rebaseline the data for trending purposes.

- Inconsistencies in data due to the increase in program scope do not influence the trend of all precursors during FY 1993–2004, as presented in an earlier section of this attachment.

3.0 Insights and Other Trends

The discussion of *significant* precursors in Section 3.1 covers the period from FY 1993 through FY 2005, although the FY 2005 results are based on the staff's screening and review of a combination of LERs and daily event notification reports (10 CFR 50.72).[8] The insights presented in the remaining sections cover the period from FY 1993 through FY 2004.

3.1 Significant Precursors

The ASP Program provides the basis for the FY 2005 performance goal measure of "zero events per year identified as a *significant* precursor of a nuclear accident" (one measure associated with the Safety Goal established in the NRC's Strategic Plan).[9] Specifically, the Strategic Plan defines a *significant* precursor as an event that has a probability of at least 1 in 1000 ($\$10^{-3}$) of leading to a reactor accident (See Reference 3).

Table 11 summarizes all *significant* precursors that occurred during the period from FY 1969 through FY 2005.

Results. Figure 2a depicts the number of *significant* precursors that occurred during FY 1993–2005. A review of the data for that period reveals the following insights:

- As of September 30, 2005, the performance goal measure for *significant* precursors has been met during the period from FY 1993 through FY 2005.

- The staff does not detect any statistically significant trend in the occurrence of *significant* precursors during FY 1993–2005.
- *Significant* precursors have occurred, on average, about once every 3 to 4 years. The events in this group involve differing failure modes, causes, and systems.

- The multiple degraded conditions coincident with degradation of the RPV head at Davis-Besse were identified as a *significant* precursor for FY 2002. The specific conditions included cracking of CRDM nozzles, degradation of the RPV head, potential clogging of the emergency sump, and potential degradation of the high-pressure injection (HPI) pumps.

- Two additional precursors with a CCDP $\$1\times10^{-3}$ have occurred during FY 1993–2005. Descriptions of these events are provided in Table 11.

3.2 Important Precursors

Precursors with a CCDP or)CDP of at least 1 in 10,000 ($\$10^{-4}$) are considered *important* in the ASP Program. An *important* precursor generally has a CCDP higher than the core damage probability (CDP) estimated by most plant-specific probabilistic risk assessments (PRAs).

The staff identified four *important* precursors that occurred during FY 2002 and FY 2003. There were no *important* precursors identified in FY 2004. As of September 30, 2005, one potential *important* precursor has been identified for FY 2005. This event occurred at Kewaunee Nuclear Power Plant and involved the potential loss of safety-related equipment as a result of postulated flooding. The staff continues to work through ASP and SDP processes to properly quantify the risk attributable to this event and determine the proper regulatory resolution.

The staff is continuing to analyze events that occurred in FY 2005 to identify additional *important* precursors. Table 12 summarizes the *important* precursor analyses completed so far.

Results. A review of the data for FY 1993–2004 reveals the following insights:

- The mean occurrence rate of *important* precursors exhibits a decreasing trend that is statistically significant during the period from FY 1993 through FY 2004, as shown in Figure 3.

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8 The staff has completed all screening and reviews through September 30, 2005.

9 Prior to FY 2005, the performance goal measure for *significant* precursors was "no more than one event per year identified as a *significant* precursor of a nuclear accident."

- *Important* precursors occur infrequently (about two per year on average).

- Twenty-two *important* precursors occurred during the period from FY 1993 through FY 2004 period. Of these, 32 percent involved a LOOP initiating event.

3.3 Initiating Events vs. Degraded Conditions

A precursor can be the result of either (1) an operational event involving an initiating event such as a LOOP, or (2) a degraded condition found during a test, inspection, or engineering evaluation. A degraded condition involves a reduction in safety system reliability or function for a specific duration (although no reactor trip initiator actually occurred during this time that challenged the degraded condition).

Results. A review of the data for FY 1993–2004 reveals the following insights:

- Over the past 12 years, precursors involving degraded conditions outnumbered initiating events (68 percent compared to 32 percent, respectively). This predominance was most notable in FY 2001 and FY 2002, when degraded conditions contributed to 91 percent and 100 percent of the identified precursors, respectively.

- The mean occurrence rate of precursors involving initiating events does not exhibit a trend that is statistically significant for the period from FY 1993 through FY 2004, as shown in Figure 5.

- The mean occurrence rate of precursors involving degraded conditions exhibits an increasing trend that is statistically significant for the period from FY 1993 through FY 2004, as shown in Figure 6. Specifically, the occurrence rate of such precursors increased over this period by a factor of two.

- Sixty-three percent of precursors involving initiating events during FY 1993–2004 are LOOP events. During the period from FY 2001 through 2004, 90 percent of all initiating event precursors involved a LOOP.

3.4 Precursors Involving Loss of Offsite Power Initiating Events

The loss of offsite power (LOOP) event at Quad Cities Station Unit 2 (FY 2001), which was attributable to a failure of the main power transformer, was the only precursor due to a LOOP that occurred in FY 2001–2002.

In FY 2003, the power blackout in the Northeast United States in August 2003 caused nine plants to lose offsite power, and the staff identified eight of those events as precursors.[10] Three additional LOOP events occurred during FY 2003. These events occurred at Palisades Nuclear Power Plant, Unit 1 of the Grand Gulf Nuclear Station, and Unit 3 of the Peach Bottom Atomic Power Station.

Six LOOP events occurred during FY 2004. The staff has completed its final analyses of the LOOP events at Palo Verde Units 1, 2, and 3, but is still conducting the remaining analyses of the events at Units 1 and 2 of the St. Lucie Nuclear Plant and Unit 3 of the Dresden Nuclear Power Station.

Results. A review of the data for FY 1993–2004 reveals the following insights:

- The mean occurrence rate of precursors resulting from a LOOP exhibits an increasing trend that is statistically significant for the period from FY 1993 through FY 2004, as shown in Figure 7. Specifically, the occurrence rate of such precursors increased over this period by a factor of three.

- Without the LOOP events that occurred as a result of the electrical blackout in the Northeast United States on August 14, 2003, the identified precursors did not exhibit any statistically significant trend (either increasing or decreasing) for the period from FY 1993 through FY 2004.

- Twenty-one percent of the LOOP precursor events that occurred during FY 1993–2004 were evaluated to be *important* precursors (CCDP $\$1\times10^{-4}$).

- A simultaneous unavailability of an emergency power system train was involved in 5 of the 33 LOOP precursor events during FY 1993–2004. One of these precursors was a *significant*

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[10] The ASP analysis of the LOOP event at Davis-Besse on August 14, 2003, showed that this event did not meet the threshold of a precursor in the ASP Program. (The CCDP was less than 1×10^{-6}.) The plant had been shut down for more than two years before this event occurred.

precursor (Catawba Unit, 1996).

3.5 Precursors at Boiling- vs. Pressurized-Water Reactors

Since FY 2001, 22 precursors have occurred at boiling-water reactors (BWRs) which is 11 more than the total from the previous 8 years. The precursor counts for pressurized-water reactors (PWRs) include the ongoing analyses of events involving cracking in CRDM housings.

A review of the data for FY 1993–2004 reveals the following results for BWRs and PWRs:

BWRs

- The mean occurrence rate of precursors at BWRs exhibits an increasing trend that is statistically significant for the period from FY 1993 through FY 2004, as shown in Figure 8. Specifically, the occurrence rate of precursors at BWRs have increased over this period by a factor of four.
- Historically, an average of 3 precursors per year occurred at BWRs during FY 1993–2004.
- Loss of offsite power events contribute to 69 percent of precursors involving initiating events at BWRs.
- Only one precursor occurred at a BWR during the 4-year period from FY 1997 through FY 2000.

PWRs

- The mean occurrence rate of precursors at PWRs does not exhibit a trend that is statistically significant for the period from FY 1993 through FY 2004, as shown in Figure 9.
- Historically, an average of 11 precursors per year occurred at PWRs during FY 1993–2004.
- Loss of offsite power events contribute to 61 percent of precursors involving initialing events at PWRs.

3.6 Precursors Caused by Degraded Conditions

Most precursors involving degraded conditions are due to equipment unavailabilities. Such events typically occur for extended periods without a reactor trip, or in combination with a reactor trip in which a risk-important component is unable to perform its safety function as a result of a degraded condition.

A review of the data for FY 1993–2004 reveals the following insights concerning the unavailability of safety-related equipment:[11]

Equipment unavailabilities at BWRs

- Of the 19 precursors involving the unavailability of safety-related equipment that occurred at BWRs during FY 1993–2004, most were caused by failures in the emergency power system (53 percent), residual heat removal system (37 percent), or high pressure coolant injection (26 percent).

Emergency core cooling systems

- An unavailability of safety-related high- and/or low-pressure injection trains contributed to 55 percent of all identified precursors that occurred at PWRs during FY 1993–2004. Most of these unavailabilities were caused by failures in either the emergency core cooling system (ECCS) (26 percent) or emergency power sources (26 percent), or resulted from design-basis issues involving other structures or systems that impact either the ECCS or one of its support systems (31 percent).
- The 19 precursors that involved a failure in an ECCS train yield the following insights:
  - Eighteen precursors involved a conditional unavailability that was identified during testing, inspection, or engineering reviews.
  - Fourteen precursors involved a condition that affected sump recirculation during postulated loss-of-coolant accidents of varying break sizes.

[11] The sum of percentages presented in this section does not always equal 100-percent because some precursors involve multiple equipment unavailabilities.

Auxiliary/emergency feedwater systems

- The unavailability of one or more trains of the auxiliary and emergency feedwater (AFW/EFW) systems contributed to 42 percent of all precursors that occurred at PWRs. Most of these unavailabilities were caused by failures in the AFW/EFW systems (22 percent) or emergency power sources (45 percent), or resulted from design-basis issues involving other structures or systems that impact either the AFW/EFW systems or one of their support systems (33 percent).

- The 12 precursors that involved a failure in an AFW/EFW train yield the following insights:

    S Five of the train failures occurred following a reactor trip.

    S Ten of the precursors involved the unavailability of the turbine-driven AFW/EFW pump train.

Emergency power sources in PWRs

The unavailability of emergency power sources such as emergency diesel generators (EDGs) and hydroelectric generators (at Oconee), contributed to 25 percent of all precursors that occurred at PWRs.[12] Most of these unavailabilities were caused by random hardware failures in the emergency power system (61 percent).

- The other unavailabilities were attributable to design-basis issues (21 percent) and losses of service water (21 percent).

- In all the analyzed LOOP events at PWRs, the turbine-driven AFW/EFW pumps were operable.

Section 3.4 (above), discusses insights related to precursors that involved a LOOP with a simultaneous EDG unavailability.

3.7 Annual ASP Index

The staff derives the annual ASP index for order-of-magnitude comparisons with industry-average core damage frequency (CDF) estimates derived from PRAs and individual plant examinations (IPEs). The index for a given fiscal year is the sum of the CCDPs and)CDPs divided by the number of reactor-calendar years.

Results. Figure 10 depicts the annual ASP indices for FY 1993–2004. A review of the ASP indices reveals the following insights:

- Based on order of magnitude, the average ASP index from FY 1993 through FY 2004 is consistent with the CDF estimates from the SPAR models and the staff's observations of the licensees' PRAs, as estimated from data gathered during SPAR benchmarking trips over the past 4 years.

- The increase in the ASP index in FYs 1994, 1996, and 2002 are attributable to the *significant* precursors that occurred in these years. Descriptions of these events are provided in Table 11.

Limitations. Using CCDPs and)CDPs from ASP results to estimate CDF is difficult because (1) the mathematical relationship requires a significant level of detail, (2) statistics for frequency of occurrence of specific precursor events are sparse, and (3) the assessment must also account for events and conditions that did not meet the ASP precursor criteria.

The ASP models and process do not explicitly address all CDF scenarios, such as fires, flooding, and external events. Thus, they are incomplete for use in estimating total CDF. In addition, using CCDPs and)CDPs can overestimate the CDF because of double counting.

Because of these and other limitations, the staff has primarily used the CCDPs and)CDPs as a relative trending indication. Nonetheless, ASP results can be linked to CDF by using an annual ASP index. The IPEs also give incomplete estimates of total CDF, although the IPEs are reasonably similar in scope to the current ASP Program.

3.8 Integrated ASP Index

The staff has modified the annual ASP index (as discussed in Section 3.7) to provide a different perspective on the contribution of precursors to the average CDF from PRAs.

12 Not all EDG unavailabilities are precursors. An EDG unavailability for a period of less than one surveillance test cycle (1 month) is screened out in the ASP Program (assuming no other complications). In addition, the risk contributions of EDG unavailabilities vary plant-to-plant and may result in a)CDP less than the threshold of a precursor (1×10^{-6}).

Specifically, the integrated ASP index, includes the risk contribution of a precursor for the entire duration of the degraded condition (i.e., the risk contribution is included in each fiscal year that the condition existed).[13] The risk contribution due to precursors involving initiating events are included in the fiscal year that the event occurred (i.e., same as the original ASP index). Examples are provided below.

Examples. A precursor involving a degraded condition is identified in FY 2003 and has a)CDP of 5×10^{-6}. A review of the LER reveals that the degraded condition existed since a design modification performed in FY 2001. In the integrated ASP index, the)CDP of 5×10^{-6} is included in the FYs 2001, 2002, and 2003.

For an initiating event occurring in FY 2003, the CCDP from this precursor is only included in FY 2003.

The index or CDF from precursors for a given fiscal year is the sum of CCDPs and)CDPs in the fiscal year divided by the number of reactor-calendar years in the fiscal year.

Results. Figure 11 depicts the integrated ASP indices for FY 1993–2004. A review of the ASP indices reveals the following insights:

- Based on order of magnitude, the average integrated ASP index for the period from FY 1993 through FY 2004 is consistent with the CDF estimates from the SPAR models and the licensee's PRAs.

- Contributions to the average integrated CDF from precursors over the 12-year period (FY 1993–2004) are as follows:

  S Four precursors contribute to nearly one-half (47 percent) of the average integrated CDF from precursors over the 12-year period. Specifically, long-term degraded conditions at Point Beach Units 1 and 2 (discovered in 2001) involved potential common-mode failure of all auxiliary feedwater pumps, while long-term degraded conditions at D.C. Cook Units 1 and 2 (discovered in 1999) involved a number of locations in the plant where the effects of postulated high-energy line break events would damage safety-related components. The associated)CDPs of the degraded conditions at Point Beach and D.C. Cook were high (7×10^{-4} and 4×10^{-4}, respectively) and the degraded conditions existed since plant construction.

  S Three *significant* precursors (i.e., CCDP or)CDP $\geq 1\times10^{-3}$) contribute to 27 percent of the average integrated CDF from precursors over the 12-year period. Each *significant* precursor existed for a one-year period. Descriptions of these events are provided in Table 11.

  S The remaining 26 percent of the average integrated CDF from precursors over the 12-year period was from contributions from 156 precursors.

Limitations. The integrated ASP index provides the contribution of risk (per fiscal year) due to precursors, and cannot be used for trending purposes since the discovery of precursors involving degraded conditions in future years may change the previous year(s) cumulative risk.

3.9 Consistency with PRAs and IPEs

A secondary objective of the ASP Program is to provide a partial validation of the dominant core damage scenarios predicted by PRAs and IPEs. Most of the identified precursor events are consistent with failure combinations identified in PRAs and IPEs.

However, a review of the precursor events for FY 1993–2004 reveals that approximately 26 percent of the identified precursors involved event initiators or failure modes that were not explicitly modeled in the PRA or IPE concerning the specific plant at which the precursor event occurred. Table 13 lists these precursors. The occurrence of these precursors does not imply that explicit modeling is needed; however, there could be insights that could be fed-back to future revisions of the PRA.

4.0 Summary

This section summarizes the ASP results, trends, and insights.

- ***Significant precursors.*** The multiple degraded conditions at Davis-Besse Nuclear Power Station represent a *significant* precursor ()CDP

13 The original ASP index reported previously included the risk contribution due to precursors only in the fiscal year in which the precursors were identified.

= 6×10^{-3}) for FY 2002. No *significant* precursors (i.e., CCDP or **)** CDP $1×10^{-3}) were identified in FYs 2003, 2004, or 2005. The ASP Program provides the basis for the FY 2005 performance goal measure of "zero events per year identified as a *significant* precursor of a nuclear accident."

These results will be reported in the NRC's Performance and Accountability Report for FY 2005 and the NRC Performance Budget for FY 2007.

- ***Important precursors.*** Four degraded conditions identified in FY 2002–2004 are *important* precursors (i.e., CCDP or **)** CDP $1×10^{-4}). These events included the multiple degraded conditions at Davis-Besse, the potential common-mode failure of auxiliary feedwater at Point Beach 1 & 2 (original design deficiency), and another potential common-mode failure of auxiliary feedwater at Point Beach 2 (potential clogging of recirculation lines).

  The NRC has already taken several actions as the result of the multiple degraded conditions at Davis-Besse. For example, the agency issued an order requiring specific inspections of the RPV head and associated penetration nozzles at PWRs. The agency also issued several bulletins, information notices, and temporary instructions (i.e., inspection procedures), as well as a regulatory issue summary.

  The degraded conditions at Point Beach resulted in the issuance of two information notices.

- ***Occurrence rate of important precursors.*** No statistically significant trend was identified in the occurrence rate of *important* precursors during the period from FY 1997 through FY 2004. A statistically significant decreasing trend was identified in the occurrence rate of *important* precursors for the longer period from FY 1993 through FY 2004.

- ***Occurrence rate of all precursors (FY 1993–2004).*** No statistically significant trend was identified in the occurrence rate of all precursors during the period from FY 1993 through FY 2004. The ITP uses this trend as one of the agency's monitored indicators.

  This result will be reported in the NRC's Performance and Accountability Report for FY 2005 and the NRC Performance Budget for FY 2007.

- ***Occurrence rate of all precursors (FY 1997–2004).*** A statistically significant increasing trend was detected in the occurrence rate of all precursors during the period from FY 1997 through FY 2004. No statistically significant trend is detected if LOOP events and degraded conditions involving cracking events in CRDM housings are removed from the data.

  In FY 2001, the agency issued a bulletin and an information notice associated with events involving cracking in CRDM housings.

  The electrical grid-related LOOP events caused by the August 2003 Northeast Blackout resulted in several agency actions prior to the summers of 2004 and 2005. These included inspections of licensee conformance with applicable NRC regulations and the raising of licensee awareness of the importance of grid reliability. References 4 and 5 provide additional insights on the risk of LOOP and station blackout events.

- ***Some observations.***

  S In the 12-year period from FY 1993 through FY 2004, precursors involving degraded conditions outnumbered initiating events by approximately two to one. From FY 1997 through FY 2004, one-half of the precursors involving degraded conditions had a condition start date prior to FY 1997.

  S Sixty-three percent of precursors involving initiating events during FY 1993–2004 were LOOP events. During the period from FY 2001 through FY 2004, 90 percent of all initiating event precursors involved a LOOP.

  S The mean occurrence rate of precursors at BWRs exhibits a statistically significant increasing trend for FY 1993–2004. Since FY 2001, 22 precursors have occurred at BWRs, which is 11 more than the total from the previous 8 years (9 of the 22 precursors involved a LOOP). Of the precursors involving the unavailability of safety-related equipment, 53 percent were caused by failures in the emergency power system, 37 percent were from failures in the residual heat removal system, and 26 percent resulted from failures in the high pressure coolant injection system. (Note that the percentages add up to more than 100 percent because e there are cases in which simultaneous failures occurred.)

- The mean occurrence rate of precursors at PWRs does not exhibit a statistically significant trend for FY 1993–2004. Of the precursors involving the unavailability of safety-related equipment, 55 percent were caused by an unavailability of high- and/or low-pressure injection trains, 42 percent were caused by the unavailability of one or more trains of the auxiliary and emergency feedwater, and 25 percent were the result of the unavailability of emergency power sources such as EDGs and hydroelectric generators. (Note that the percentages add up to more than 100 percent because there are cases in which simultaneous failures occurred.)

- The average integrated ASP index, which sums the risk contribution of precursors on a reactor-calendar year basis, is consistent with the average core damage frequency estimates from the SPAR models and the licensees' PRAs.

- A review of the precursor events for FY 1993–2004 reveals that approximately 26 percent of the identified precursors involved event initiators or failure modes that were not explicitly modeled in the PRA or IPE concerning the specific plant at which the precursor event occurred. The occurrence of these precursors does not imply that explicit modeling is needed; however, there could be insights that could be fed back to future revisions of the PRA.

5.0 References

1. U.S. Nuclear Regulatory Commission. NUREG/CR-5750, "Rates of Initiating Events at U.S. Nuclear Power Plants: 1987–1995." NRC: Washington, DC. February 1999.

2. Rasmuson, D.M., and P.D. O'Reilly. "Analysis of Annual Accident Sequence Precursor Occurrence Rates for 1984–94," in *Proceeding of the International Topical Meeting on Probabilistic Safety Assessment*. American Nuclear Society (ANS), Park City, Utah. 29 September – 3 October, 1996. Vol. III, pp. 1645–1652. ANS: LaGrange Park, Illinois. 1994.

3. U.S. Nuclear Regulatory Commission. NUREG-1100, Vol. 21, "Performance Budget, Fiscal Year 2006." NRC: Washington, DC. February 2005.

4. U.S. Nuclear Regulatory Commission. NUREG/CR-XXXX (INEEL/EXT-04-02525), "Station Blackout Risk Evaluation for Nuclear Power Plants (Draft)" NRC: Washington, DC. January 2005.

5. U.S. Nuclear Regulatory Commission. NUREG/CR-XXXX (INEEL/EXT-04-02326), "Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1986–2003 (Draft)" NRC: Washington, DC. October 2004.

Table 1. Status of ASP analyses (as of September 30, 2005).

Status	FY 2001	FY 2002	FY 2003	FY 2004	FY 2005[a]
Analyzed events that were determined not to be precursors	32	21	23	17	4
Preliminary precursor analyses underway	5[b]	4[b]	1[b]	1	7
Preliminary precursor analyses completed	0	0	1	9	3
Final precursor analyses completed	17	10	20	6	0
Total precursors identified	22	14	22	16[c]	10[c]

a. As of September 30, 2005, the staff has not yet screened all of the FY 2005 events and unavailabilities.
b. Events involving cracking of control rod drive mechanism housings. The analyses for these events have not been completed and, therefore, the number of precursors attributable to cracking of CRDM housings may change.
c. All of the reviews and analyses for FY 2004 and FY 2005 events have not been completed, and therefore, the number of total precursors for these years may change.

Table 2. FY 2001 precursors involving initiating events.

Event Date	Plant	Description	CCDP[a]
8/2/01	Quad Cities 2	Plant-centered LOOP due to a transformer failure. ***Licensee Event Report (LER) 265/01-001***	5×10^{-6}
9/3/01	LaSalle 2	Reactor scram, loss of offsite power to vital bus (blown fuses), and subsequent unavailabilities: core spray pump, residual heat removal pump, and control rod drive pump. ***LER 374/01-003***	1×10^{-5}

a. Conditional core damage probability.

Table 3. FY 2001 precursors involving degraded conditions.

Event Date[a]	Condition Duration[b]	Plant	Description	) CDP[c]
11/1/00	> 11 years	Prairie Island 1	Potential unavailability of service water (SW) pumps due to improper design modification of backflush system and failure of vacuum valves. ***LER 282/00-004, LER 282/00-003***	1×10^{-6}
11/1/00	> 11 years	Prairie Island 2	Potential unavailability of SW pumps due to improper design modification of backflush system and failure of vacuum valves. ***LER 282/00-004, LER 282/00-003***	1×10^{-6}
2/23/01	1944 hours	Limerick 2	Inadvertent opening/stuck open main steam relief valve (MSRV). ***LER 353/01-001***	3×10^{-6}
3/28/01	6185 hours	Fermi 2	EDG “14” unavailable due to degraded bearing. ***LER 341/01-001***	3×10^{-6}
4/23/01	201 days	Surry 1	EDG “3” unavailable due to abnormal wear of piston rings. ***LER 280/01-001***	3×10^{-6}
4/23/01	201 days	Surry 2	EDG “3” unavailable due to abnormal wear of piston rings. ***LER 280/01-001***	6×10^{-6}
4/30/01	> 28 years	Oconee 1	Potential unavailability of high pressure injection (HPI) and component cooling water (CCW) pumps due to flooding caused by a postulated break on non-seismically qualified piping. ***Inspection Report (IR) 269/00-008***	4×10^{-6}
4/30/01	> 28 years	Oconee 2	Potential unavailability of HPI and CCW pumps due to flooding caused by a postulated break on non-seismically qualified piping. ***IR 270/00-008***	1×10^{-6}
4/30/01	> 28 years	Oconee 3	Potential unavailability of HPI and CCW pumps due to flooding caused by a postulated break on non-seismically qualified piping. ***IR 287/00-008***	1×10^{-6}
5/16/01	> 1 year	Calvert Cliffs 1	TDAFW pump inoperable due to sealant intrusion. ***LER 317/01-001***	1×10^{-5}
7/5/01	2088 hours	Dresden 3	HPCI inoperable due to water hammer event. ***LER 249/02-005***	3×10^{-6}
8/9/01	> 12 years	D.C. Cook 2	Concurrent unavailabilities– EDGs potentially unavailable due to lack of essential service water (ESW) flow caused by a deformed SW strainer and TDAFW pump inoperable due to failed latching mechanism. ***LER 316/01-003***	7×10^{-6}
8/20/01	> 25 years	ANO 1	Potential unavailability of safety-related equipment during a postulated fire due to improper fire protection and procedures. ***LER 313/01-006***	4×10^{-6}
8/29/01	> 12 years	D.C. Cook 1	Concurrent unavailabilities– EDGs potentially unavailable due to lack of ESW flow caused by a deformed SW strainer and TDAFW pump inoperable due to failed latching mechanism. ***LER 316/01-003***	1×10^{-5}

Event Date[a]	Condition Duration[b]	Plant	Description	ΔCDP[c]
9/11/01	> 29 years	Palisades	Potential unavailability of safety-related equipment during a postulated fire due to improper installation of smoke detectors. ***IR 255/01-008***	1×10^{-6}

a. Condition duration is the time period when the degraded condition existed. The ASP Program limits the analysis exposure time of degraded condition to 1 year.
b. ASP event date is the discovery date for a precursor involving a degraded condition.
c. Increase in core damage probability (i.e., conditional core damage probability - core damage probability).

Table 4. FY 2001–2005 CRDM cracking events.[a, b]

Event Date	Plant	Description
12/4/00	Oconee 1	Reactor pressure vessel (RPV) head leakage due to primary water stress corrosion cracking (PWSCC) of five thermocouple nozzles and one CRDM nozzle. ***LER 269/00-006, LER 269/02-003, LER 269/03-002***
2/18/01	Oconee 3	RPV head leakage due to PWSCC of nine CRDM nozzles. ***LER 287/01-001, LER 287/00-003, LER 287/03-001***
3/24/01	ANO 1	RPV head leakage due to PWSCC of one CRDM nozzle. ***LER 313/01-002, LER 313/02-003***
4/28/01	Oconee 2	RPV head leakage due to PWSCC of four CRDM nozzles. ***LER 270/01-002, LER 270/02-002***
6/21/01	Palisades	RPV head leakage due to PWSCC of one CRDM nozzle. ***LER 255/01-002, LER 255/01-004***
10/1/01	Crystal River 3	RPV head leakage due to PWSCC of one CRDM nozzle. ***LER 302/01-004***
10/12/01	TMI 1	RPV head leakage due to PWSCC of eight thermocouple nozzles and five CRDM nozzles. ***LER 289/01-002***
10/28/01	Surry 1	RPV head leakage due to PWSCC of two CRDM nozzles. ***LER 280/01-003***
11/13/01	North Anna 2	RPV head leakage due to PWSCC of one CRDM nozzle. ***LER 339/01-003, LER339/02-001***
4/30/03	St. Lucie 2	RPV head leakage due to PWSCC of two CRDM nozzles. ***LER 389/03-002***

a. The analyses of cracking events are ongoing. The risk associated with multiple cracks at a given plant will be considered collectively in one analysis for each plant (i.e., only one precursor for each plant).
b. The reviews and analyses for these events have not been completed and, therefore, the number of precursors due to cracking of CRDM housings may change.

Table 5. FY 2002 precursors involving initiating events.

Event Date	Plant	Description	CCDP
		None	

Table 6. FY 2002 precursors involving degraded conditions.

Event Date[a]	Condition Duration[b]	Plant	Description	ΔCDP
10/8/01	> 2 years	Shearon Harris 1	RHR Train “A” unavailable for sump recirculation due to debris entrapment and RHR Train “B” potentially unavailable due to an inoperable isolation valve. ***LER 400/01-003***	6×10^{-6}
11/29/01	> 30 years	Point Beach 1	Concurrent unavailabilities– potential common-cause failure of all EFW due to design deficiency of minimum flow recirculation valves and potential loss of feed-and-bleed capability during postulated loss of instrument air (LOIA). ***LER 266/01-005***	6×10^{-4}
11/29/01	> 29 years	Point Beach 2	Concurrent unavailabilities– potential common-cause failure of all EFW due to design deficiency of minimum flow recirculation valves and potential loss of feed-and-bleed capability during postulated LOIA. ***LER 266/01-005***	7×10^{-4}
12/3/01	> 1 year	Callaway	Concurrent unavailabilities– potential unavailability of ESW Pump “B” and MDAFW Pump “B” due to foreign material and CCW Pump “B” out for test and maintenance. ***LER 483/01-002***	1×10^{-5}
12/18/01	> 13 years	Shearon Harris 1	Degraded fire barrier and lack of fire brigade training could cause unavailability of Train “B” safety equipment and TDAFW pump flow control. ***IR 400/00-009***	6×10^{-6}
2/14/02	5216 hours	Columbia	Potential unavailability of four safety-related breakers due to degraded MOC switches. ***LER 397/02-001***	6×10^{-6}
2/27/02	> 1 year	Davis-Besse	RPV head leakage due to PWSCC of CRDM nozzles, potential unavailability of sump recirculation due to screen plugging, and potential unavailability of boron precipitation control. ***LER 346/02-002***	6×10^{-3}
4/16/02	> 2 years	Braidwood 1	Inoperable power operated relief valve (PORV) bleed path due to leaking air accumulators. ***LER 456/02-002***	4×10^{-6}
5/30/02	> 1 year	Oconee 3	Potential unavailability of a HPI pump due to improperly installed wire connectors during a postulated severe LOOP or high energy line break (HELB). ***IR 270/02-015***	3×10^{-6}
7/19/02	> 23 years	Indian Point 2	Degraded control room fire barrier. ***IR 247/02-010***	7×10^{-6}

a. Condition duration is the time period when the degraded condition existed. The ASP Program limits the analysis exposure time of degraded condition to one year.
b. ASP event date is the discovery date for a precursor involving a degraded condition.

Table 7. FY 2003 precursors involving initiating events.

Event Date	Plant	Description	CCDP
3/25/03	Palisades	Plant-centered LOOP (Mode 6) and temporary loss of shutdown cooling. ***LER 255/03-003***	3×10^{-6}
4/24/03	Grand Gulf 1	Plant-centered LOOP and subsequent loss of the instrument air system. ***LER 416/03-002***	1×10^{-6}
8/14/03	Indian Point 2	Grid-related LOOP due to August 14, 2003 Northeast Blackout. ***LER 247/03-005***	6×10^{-6}
8/14/03	Indian Point 3	Grid-related LOOP due to August 14, 2003 Northeast Blackout. ***LER 247/03-005***	7×10^{-6}
8/14/03	Nine Mile Point 1	Grid-related LOOP due to August 14, 2003 Northeast Blackout. ***LER 220/03-002***	2×10^{-5}
8/14/03	Nine Mile Point 2	Grid-related LOOP due to August 14, 2003 Northeast Blackout. ***LER 410/03-002***	2×10^{-5}
8/14/03	Fitzpatrick	Grid-related LOOP due to August 14, 2003 Northeast Blackout. ***LER 333/03-001***	4×10^{-6}
8/14/03	Ginna	Grid-related LOOP due to August 14, 2003 Northeast Blackout. ***LER 244/03-002***	3×10^{-5}
8/14/03	Perry 1	Grid-related LOOP due to August 14, 2003 Northeast Blackout. ***LER 440/03-002***	3×10^{-5}
8/14/03	Fermi 2	Grid-related LOOP due to August 14, 2003 Northeast Blackout. ***LER 341/03-002***	2×10^{-5}
9/15/03	Peach Bottom 3	Plant-centered LOOP, an emergency diesel generator unavailable, and stuck open safety relief valve. ***LER 227/03-004***	3×10^{-6}

Table 8. FY 2003 precursors involving degraded conditions.

Event Date[a]	Condition Duration[b]	Plant	Description	ΔCDP
10/29/02	> 1 year	Point Beach 1	Potential common-mode failure of all EFW pumps due to clogging of recirculation lines during switchover to service water. ***LER 266/02-003***	6×10^{-5}
10/29/02	> 1 year	Point Beach 2	Potential common-mode failure of all EFW pumps due to clogging of recirculation lines during switchover to service water. ***LER 266/02-003***	4×10^{-4}
10/30/02	> 29 years	Kewaunee	Potentially unavailable safety-related equipment due to lack of fixed fire suppression system. ***IR 305/02-006***	1×10^{-5}
12/20/02	> 1 year	Shearon Harris 1	Postulated fire could cause the actuation of certain valves that could result in a loss of the charging pump, RCP seal cooling, loss of RCS inventory, and other conditions. ***LER 400/02-004***	9×10^{-6}
2/26/03	28 hours	Kewaunee	Concurrent unavailabilities– EDG “B” inoperable due to faulty relay and EDG “A” out for test and maintenance. ***LER 305/03-002***	4×10^{-6}
3/7/03	> 1 year	Nine Mile Point 1	Potential unavailability of reactor building closed loop cooling system due to degraded piping. ***IR 220/03-03***	4×10^{-6}
5/20/03	164 hours	Oyster Creek	Loss of 4.16kV Emergency Bus “1C” due to ground fault in normally energized underground cable. ***LER 219/03-002***	1×10^{-6}
7/1/03	504 hours	Hope Creek 1	Station service water Train “A” traveling screen failed due to inadequate maintenance instructions. ***IR 354/03-006***	3×10^{-6}
9/1/03	550 hours	Perry 1	ESW pump “A” failure to run due to shaft failure and inadequate repairs led to a second failure. ***LER 440/03-004***	1×10^{-6}
9/29/03	4 months	Waterford 3	Degraded EDG due to failed fuel line. ***LER 382/03-002***	2×10^{-6}

a. Condition duration is the time period when the degraded condition existed. The ASP Program limits the analysis exposure time of degraded condition to one year.
b. ASP event date is the discovery date for a precursor involving a degraded condition.

Table 9. FY 2004 precursors involving initiating events (as of September 30, 2005).

Event Date	Plant	Description	CCDP
1/4/04	Calvert Cliffs 2[a]	Reactor trip caused by loss of main feedwater and complicated by a failed relay causing overcooling. ***LER 318/04-001***	2×10^{-5}
5/5/04	Dresden 3[a]	Plant-centered LOOP due to breaker malfunction. ***LER 249/04-003***	3×10^{-6}
6/14/04	Palo Verde 1	Grid-related LOOP with offsite power recovery complications due to breaker failure. ***LER 528/04-006***	9×10^{-6}
6/14/04	Palo Verde 2	Grid-related LOOP with an emergency diesel generator unavailable. ***LER 528/04-006***	4×10^{-5}
6/14/04	Palo Verde 3	Grid-related LOOP with offsite power recovery complications due to breaker failure. ***LER 528/04-006***	9×10^{-6}
9/25/04	St. Lucie 1[a]	Severe weather LOOP caused by Hurricane Jeanne while the plant was shut down. ***LER 335/04-004***	1×10^{-5}
9/25/04	St. Lucie 2[a]	Severe weather LOOP caused by Hurricane Jeanne while the plant was shut down. ***LER 335/04-004***	1×10^{-5}

a. Preliminary analysis results may change pending comments from peer review.

Table 10. FY 2004 precursors involving degraded conditions (as of September 30, 2005).

Event Date[a]	Condition Duration[b]	Plant	Description	)CDP
11/3/03	> 30 years	Surry 1	Potential loss of reactor coolant pump (RCP) seal cooling due to postulated fire damage to emergency switchgear. ***LER 280/03-005***	1×10^{-6}
11/3/03	> 30 years	Surry 2	Potential loss of RCP seal cooling due to postulated fire damage to emergency switchgear. ***LER 280/03-005***	1×10^{-6}
1/4/04	720 hours	Brunswick 2	EDG “3” unavailable due to jacket water leak. ***LER 325/04-001***	2×10^{-6}
1/30/04	> 2 years	Dresden 2[c]	HPCI potentially unavailable due to water carryover into steam line caused by feedwater level control failure. ***LER 249/04-002***	3×10^{-6}
1/30/04	> 2 years	Dresden 3[c]	HPCI potentially unavailable due to water carryover into steam line caused by feedwater level control failure. ***LER 249/04-002***	3×10^{-6}
3/17/04	1117 hours	Peach Bottom 3[c]	HPCI unavailable due to failed flow controller. ***LER 278/04-001***	2×10^{-6}
7/31/04	> 11 years	Palo Verde 1[c]	Containment sump recirculation potentially inoperable due to pipe voids. ***LER 528/04-009***	4×10^{-5}
7/31/04	> 11 years	Palo Verde 2[c]	Containment sump recirculation potentially inoperable due to pipe voids. ***LER 528/04-009***	4×10^{-5}
7/31/04	> 11 years	Palo Verde 3[c]	Containment sump recirculation potentially inoperable due to pipe voids. ***LER 528/04-009***	4×10^{-5}

a. Condition duration is the time period when the degraded condition existed. The ASP Program limits the analysis exposure time of degraded condition to one year.
b. ASP event date is the discovery date for a precursor involving a degraded condition.
c. Preliminary analysis results may change pending comments from peer review.

Table 11. *Significant* (CCDP or)CDP $1×$10^{-3}$) accident sequence precursors during the 1969–2005 period—ordered by event date. *(See notes)*

Plant	)CDP or CCDP	Date	Description
Davis-Besse	6×10^{-3}	2/27/02	**Multiple conditions coincident with reactor pressure vessel (RPV) head degradation** The analysis included multiple degraded conditions discovered on various dates. These conditions included cracking of control rod drive mechanism (CRDM) nozzles and reactor pressure vessel (RPV) head degradation; potential clogging of the emergency sump; and potential degradation of the high-pressure injection (HPI) pumps during recirculation. ***LER 346/02-002***
Catawba 2	2×10^{-3}	2/6/96	**Loss of offsite power (LOOP) with an emergency diesel generator (EDG) unavailable** When the reactor was at hot shutdown, a transformer in the switchyard shorted out during a storm, causing breakers to open and resulting in a LOOP event. Although both EDGs started, the output breaker of EDG “1B” to essential bus “1B” failed to close on demand, leaving bus “1B” without AC power. After 2 hours and 25 minutes, operators successfully closed the EDG “1B” output breaker. ***LER 414/96-001***
Wolf Creek 1	3×10^{-3}	9/17/94	**Reactor coolant system (RCS) blowdown to refueling water storage tank (RWST)** When the plant was in cold shutdown, operators implemented two unpermitted simultaneous evolutions, which resulted in the transfer of 9,200 gallons (34,825 liters) of RCS inventory to the RWST. Operators immediately diagnosed the problem and terminated the event by closing the residual heat removal (RHR) cross-connect motor-operated valve (MOV). The temperature of the RCS increased by 7 °F (4 °C) as a result of this event. ***LER 482/94-013***
Harris 1	6×10^{-3}	4/3/91	**HPI unavailability for one refueling cycle** A degraded condition resulted from relief valve and drain line failures in the alternative minimum flow systems for the charging/safety injection pumps, which would have diverted a significant amount of safety injection flow away from the reactor coolant system. The root cause of the degradation is believed to have been water hammer, as a result in air left in the alternative minimum flow system following system maintenance and test activities. ***LER 400/91-008***
Turkey Point 3	1×10^{-3}	12/27/86	**Turbine load loss with trip; control rod drive (CRD) auto insert fails; manual reactor trip; power operated relief valve (PORV) sticks open** The reactor was tripped manually following a loss of turbine governor oil system pressure and the subsequent rapid electrical load decrease. Control rods failed to insert automatically because of two cold solder joints in the power mismatch circuit. During the transient, a PORV opened but failed to close (the block valve had to be closed). The loss of governor oil pressure was due to a cleared orifice blockage and the auxiliary governor dumping control oil. ***LER 250/86-039***

Plant	)CDP or CCDP	Date	Description
Catawba 1	3×10^{-3}	6/13/86	**Chemical and volume control system (CVCS) leak (130 g.p.m.) from the component cooling water (CCW)/CVCS heat exchanger joint (i.e., small-break loss-of-coolant accident (LOCA))** A weld break on the letdown piping, near the CCW/CVCS heat exchanger caused excessive RCS leakage. A loss of motor control center (MCC) power caused the variable letdown orifice to fail open. The weld on the 1-inch (2.54-cm) outlet flange on the variable letdown orifice failed as a result of excessive cavitation-induced vibration. This event was a small-break LOCA. ***LER 413/86-031***
Davis-Besse	1×10^{-2}	6/9/85	**Loss of feedwater; scram; operator error fails auxiliary feedwater (EFW); PORV fails open** While at 90-percent power, the reactor tripped with main feedwater (MFW) pump “1” tripped and MFW pump “2” unavailable. Operators made an error in initiating the steam and feedwater rupture control system and isolated EFW to both steam generators (SGs). The PORV actuated three times and did not reseat at the proper RCS pressure. Operators closed the PORV block valves, recovered EFW locally, and used HPI pump “1” to reduce RCS pressure. ***LER 346/85-013***
Hatch 1	2×10^{-3}	5/15/85	**Heating, ventilation, and air conditioning (HVAC) water shorts panel; safety relief valve (SRV) fails open; high-pressure coolant injection (HPCI) fails; reactor core isolation cooling (RCIC) unavailable** Water from an HVAC vent fell onto an analog transmitter trip system panel in the control room (the water was from the control room HVAC filter deluge system which had been inadvertently activated as a result of unrelated maintenance activities). This resulted in the lifting of the SRV four times. The SRV stuck open on the fourth cycle initiating a transient. Moisture also energized the HPCI trip solenoid making HPCI inoperable. RCIC was unavailable due to maintenance. ***LER 321/85-018***
Lasalle 1	2×10^{-3}	9/21/84	**Operator error causes scram; RCIC unavailable; RHR unavailable** While at 23-percent power, an operator error caused a reactor scram and MSIV closure. RCIC was found to be unavailable during testing (one RCIC pump was isolated and the other pump tripped during the test). RHR was found to be unavailable during testing due to an inboard suction isolation valve failing to open on demand. Both RHR and RCIC may have been unavailable after the reactor scram. ***LER 373/84-054***
Salem 1	5×10^{-3}	2/25/83	**Trip with automatic reactor trip capability failed** When the reactor was at 25-percent power, both reactor trip breakers failed to open on demand of a low-low SG level trip signal. A manual trip was initiated approximately 3 seconds after the automatic trip breaker failed to open, and was successful. The same event occurred 3 days later, at 12-percent power. Mechanical binding of the latch mechanism in the breaker under-voltage trip attachment failed both breakers in both events. ***LER 272/83-011***

Plant	)CDP or CCDP	Date	Description
Davis-Besse	2×10^{-3}	6/24/81	**Loss of vital bus; failure of an EFW pump; main steam safety valve lifted and failed to reseat** With the plant at 74-percent power, the loss of bus “E2” occurred due to a maintenance error during CRDM breaker logic testing. A reactor trip occurred, due to loss of CRDM power (bus “E2”), and instrumentation power was also lost (bus “E2” and a defective logic card on the alternate source). During the recovery, EFW pump “2” failed to start due to a maladjusted governor slip clutch and bent low speed stop pin. A main steam safety valve lifted, and failed to reseat (valve was then gagged). ***LER 346/81-037***
Brunswick 1	7×10^{-3}	4/19/81	**RHR heat exchanger damaged** While the reactor was in cold shutdown during a maintenance outage, the normal decay heat removal system was lost because of a failure of the single RHR heat exchanger that was currently in service. The failure occurred when the starting of a second RHR service water pump caused the failure of a baffle in the waterbox of the RHR heat exchanger, thereby allowing cooling water to bypass the tube bundle. The redundant heat exchanger was inoperable because maintenance was in progress. ***LER 325/81-032***
Millstone 2	5×10^{-3}	1/2/81	**Loss of DC power and one EDG as a result of operator error; partial LOOP** When the reactor was at full power, the 125v DC emergency bus was lost as a result of operator error. The loss of the bus caused the reactor to trip, but the turbine failed to trip because of the unavailability of DC bus “A.” Loads were not switched to the reserve transformer (following the manual turbine trip) because of the loss of DC bus “A.” Two breakers (on the “B” 6.9kV and 4.16kV buses) remained open, thereby causing a LOOP. EDG “B” tripped as a result of leakage of the service water (SW) flange, which also caused the “B” 4.16 kV bus to be de-energized. An operator recognition error caused the PORV to be opened at 2380 psia. ***LER 336/81-005***
St. Lucie 1	1×10^{-3}	6/11/80	**Reactor coolant pump seal LOCA due to loss of component cooling water (CCW); top vessel head bubble** At 100-percent power, a moisture-induced short circuit in a solenoid valve caused a CCW containment isolation valve to shut causing loss of CCW to all reactor coolant pumps (RCPs). While reducing pressure to initiate the shutdown cooling system (SCS), the top head water flashed to steam, thus forming a bubble (initially undetected by the operators). During the cooldown, the SCS relief valves lifted and low-pressure safety injection (LPSI) initiated (i.e., the other LPSI pump started charging, while the other was used for cooldown). ***LER 335/80-029***
Davis-Besse	1×10^{-3}	4/19/80	**Loss of two essential busses** When the reactor was in cold shutdown, two essential busses were lost due to breaker ground fault relay actuation during an electrical lineup. Decay heat drop line valve was shut, and air was drawn into the suction of the decay heat removal pumps, resulting in loss of a decay heat removal path. ***LER 346/80-029***

Plant	)CDP or CCDP	Date	Description
Crystal River 3	5×10^{-3}	2/26/80	**Loss of 24-volt DC power to non-nuclear instrumentation (NNI)** The 24-volt power supply to the NNI was lost as a result of a short to ground. This initiated a sequence of events in which the PORV opened (and stayed open) as a direct result of the loss of the NNI power supply. HPI initiated as a result of depressurization through the open PORV, and with approximately 70 percent of NNI inoperable or inaccurate, the operator correctly decided that there was insufficient information available to justify terminating HPI. Therefore, the pressurizer was pumped solid, one safety valve lifted, and flow through the safety valve was sufficient to rupture the reactor coolant drain tank rupture disk, thereby spilling approximately 43,000 gallons (162,800 liters) of primary water into the containment. ***LER 302/80-010***
Hatch 2	1×10^{-3}	6/3/79	**Loss of feedwater; HPCI fails to start; RCIC is unavailable** During a power increase, the reactor tripped due to a condensate system trip. HPCI failed to initiate on low-low level due to a failed turbine stop valve. In addition, water from leaking mechanical seal lines and an unknown valve caused water to back up and contaminate the pump oil. RCIC was out of service for unspecified reasons. ***LER 366/79-045***
Oyster Creek	2×10^{-3}	5/2/79	**Loss of feedwater flow** While testing the isolation condenser, a reactor scram occurred. The feedwater pump tripped and failed to restart. The recirculation pump inlet valves were closed. The isolation condenser was used during cooldown. ***LER 219/79-014***
Three Mile Island 2	1	3/28/79	**Loss of feedwater; PORV failed open; operator errors led to core damage** Operators misinterpreted plant conditions, including the RCS inventory, during a transient that was triggered by a loss of feedwater and a stuck-open PORV. As a result, the operators prematurely shut off the high-pressure safety injection system, turned off the reactor coolant pumps, and failed to diagnose and isolate a stuck-open pressurizer relief valve. With the no RCS inventory makeup, the core became uncovered and fuel damage occurred. In addition, contaminated water was spilled into the containment and auxiliary buildings. ***LER 320/79-012***
Salem 1	1×10^{-2}	11/27/78	**Loss of vital bus and scram; multiple components lost** While the reactor was at 100-percent power, vital instrument bus "1B" was lost as a result of the failure of an output transformer and two regulating resistors. Loss of the vital bus caused a false low RCS loop flow signal, thereby causing a reactor trip. Two EFW pumps failed to start (one because of the loss of vital bus "1B", and the other because of a maladjustment of the over-speed trip mechanism). Inadvertent safety injection occurred as a result of decreasing average coolant temperature and safety injection signals. ***LER 272/78-073***
Calvert Cliffs 1	3×10^{-3}	4/13/78	**LOOP; one EDG failed to start** With the plant shut down, a protective relay automatically opened the switchyard breakers, resulting in a LOOP. EDG "11" failed to start. EDG "22" started and supplied the safety busses. ***LER 317/78-020***

Plant	)CDP or CCDP	Date	Description
Farley 1	5×10^{-3}	3/25/78	**Low-Low water level in one SG trip/scram; turbine-driven EFW pump fails** A low level condition in a single SG resulted in a reactor trip. The turbine-driven EFW pump failed to start. Both motor-driven EFW pumps started, but were deemed ineffective because all recirculation bypass valves were open (thereby diverting flow). A recirculation valve was manually closed. ***LER 348/78-021***
Rancho Seco	1×10^{-1}	3/20/78	**Failure of NNI and steam generator dryout** When the reactor was at power, a failure of the NNI power supply resulted in a loss of main feedwater, which caused a reactor trip. Because instrumentation drift falsely indicated that the steam generator contained enough water, control room operators did not take prompt action to open the EFW flow control valves to establish secondary heat removal. This resulted in steam generator dryout. ***LER 312/78-001***
Davis-Besse	5×10^{-3}	12/11/77	**EFW pumps inoperable during test** During EFW pump testing, operators found that control over both pumps was lost because of mechanical binding in the governor of one pump and blown control power supply fuses for the speed changer motor on the other pump. ***LER 346/77-110***
Davis-Besse	7×10^{-2}	9/24/77	**Stuck-open pressurizer PORV** A spurious half-trip of the steam and feedwater rupture control system initiated closure of the startup feedwater valve. This resulted in reduced water level in SG "2." The pressurizer PORV lifted nine times and then stuck open because of rapid cycling. ***LER 346/77-016***
Cooper	1×10^{-3}	8/31/77	**Partial loss of feedwater; reactor scram; RCIC and HPCI degraded** A blown fuse caused the normal power supply to the feedwater and RCIC controllers to fail. The alternate power supply was unavailable due to an unrelated fault. A partial loss of feedwater occurred, and the reactor tripped on low water level. RCIC and HPCI operated, however, both pumps did not accelerate to full speed (RCIC due to the failed power supply and HPCI due a failed governor actuator). ***LER 298/77-040***
Zion 2	2×10^{-3}	7/12/77	**Testing causes instrumentation errors** With the reactor in hot shutdown, testing caused operators to lose indications of reactor and secondary system parameters. In addition, inaccurate inputs were provided to control and protection systems. ***LER 304/77-044***
Millstone 2	1×10^{-2}	7/20/76	**LOOP from grid disturbance; errors in EDG loading fail the emergency core cooling systems (ECCS)** With the reactor at power, a main circulating water pump was started, and this resulted in an in-plant voltage reduction to below the revised trip set point. This isolated the safety-related buses and started the EDGs. Each time a major load was tied onto the diesel, the revised under-voltage trip set points tripped the load. As a result, at the end of the EDG loading sequence, all major loads were isolated, even though the EDGs were tied to the safety-related buses. ***LER 336/76-042***

Plant	)CDP or CCDP	Date	Description
Kewaunee	5×10^{-3}	11/5/75	**Inoperable EFW pumps during startup as a result of leaks from the demineralizer into the condensate storage tank (CST)** Mixed bed resin beads were leaking from the demineralizer in the makeup water system and migrated to the CST. As a result, during startup, both motor-driven EFW pump suction strainers became clogged, thereby resulting in low pump flow. The same condition occurred for the turbine-driven EFW pump suction strainer. ***LER 305/75-020***
Brunswick 2	9×10^{-3}	4/29/75	**Multiple valve failures; RCIC inoperable as a result of stuck-open down/safety valve** At 10-percent power, the RCIC system was determined to be inoperable, and SRV “B” was stuck open. The operator failed to scram the reactor according to the EOPs. HPCI system failed to run and was manually shut down as a result of high torus level. Loop “B” of RHR failed as a result of a failed service water supply valve to the heat exchanger. The reactor experienced an automatic scram on manual closure of the main steam isolation valve (MSIV). ***LER 324/75-013***
Browns Ferry 1	2×10^{-1}	3/22/75	**Cable tray fire** The fire was started by an engineer, who was using a candle to check for air leaks through a firewall penetration seal to the reactor building. The fire resulted in significant damage to cables related to the control of Units 1 and 2. All Unit 1 emergency core cooling systems were lost, as was the capability to monitor core power. Unit 1 was manually shut down and cooled using remote manual relief valve operation, the condensate booster pump, and control rod drive system pumps. Unit 2 was shut down and cooled for the first hour by the RCIC system. After depressurization, Unit 2 was placed in the RHR shutdown cooling mode with makeup water available from the condensate booster pump and control rod drive system pump. ***LER 259/75-006***
Turkey Point 3	2×10^{-2}	5/8/74	**Failure of three EFW pumps to start during test** Operators attempted to start all three EFW pumps while the reactor was at power for testing. Two of the pumps failed to start as a result of over-tightened packing. The third pump failed to start because of a malfunction in the turbine regulating valve pneumatic controller. ***LER 250/74-LTR***
Point Beach 1	5×10^{-3}	4/7/74	**Inoperable EFW pumps during shutdown** While the reactor was in cooldown mode, motor-driven EFW pump “A” did not provide adequate flow. The operators were unaware that the in-line suction strainers were 95 percent plugged (both motor-driven pumps “A” and “B”). A partially plugged strainer was found in each of the suction lines for both turbine-driven EFW pumps. ***LER 266/74-LTR***

Plant	ΔCDP or CCDP	Date	Description
Point Beach 1	1×10^{-3}	1/12/71	**Failure of containment sump valves** During a routine check of the containment tendon access gallery, air was observed leaking from the packing of one sump isolation valve. Operators attempted to open the valve, but the valve failed to open due to a shorted solenoid in the hydraulic positioner. The redundant sump isolation valve was also found inoperable due to a stuck solenoid in the hydraulic positioner. ***LER 266/71-LTR***

*NOTES:
- Events are selected on the basis of CCDPs, as estimated by the ASP Program.
- Because of model and data uncertainties, it is difficult to differentiate between events with CCDPs that are within a factor of about 3.
- ASP analyses have been performed since 1969, and the associated methodologies and PRA models have evolved over the past 35 years. Consequently, the results obtained in the earlier years may be conservative when compared to those obtained using the current methodology and PRA models.

Table 12. FY 2001–2005 *important* precursors (as of September 30, 2005).

Plant	Description/Event Identifier	Event Date	ΔCDP
Point Beach 1 & 2	This condition involved a design deficiency in the air-operated minimum-flow recirculation valves of the EFW pumps. The valves fail closed on loss of instrument air, and this could potentially lead to pump deadhead conditions and a common-mode, non-recoverable failure of the EFW pumps. Because the pressurizer PORVs also depend on instrument air, an event involving a loss of instrument air may also result in the loss of feed-and-bleed cooling capability. ***LER 266/01-005***	11/29/01	7×10^{-4} (Both Units)
Davis-Besse	Cracking of CRDM nozzles, RPV head degradation, potential clogging of the emergency sump, and potential degradation of the HPI pumps. ***LER 346/02-002***	2/27/02	6×10^{-3}
Point Beach 2	This condition involved a design deficiency in the flow-restricting orifices in the recirculation lines of the EFW pumps. Because of this design deficiency, the orifices are vulnerable to debris plugging when the suction supply for the EFW pumps is switched to its safety-related water supply (the service water system). Blocked flow in the recirculation lines of the EFW pumps, combined with inadequacies in plant emergency operating procedures, could potentially lead to pump deadhead conditions and a common-mode, non-recoverable failure of the pumps. The mean ΔCDP was 6×10^{-5} for Unit 1. ***LER 266/02-003***	10/29/02	4×10^{-4}

Table 13. Precursors involving failure modes and event initiators that were not explicitly modeled in the PRA or IPE concerning the specific plant at which the precursor event occurred.

Plant	Year	Event Description
Calvert Cliffs 2	2004	Failed relay causes overcooling condition during reactor trip. ***LER 318/04-001***
Dresden 2 & 3	2004	HPCI potentially unavailable due to water carryover into steam line caused by feedwater level control failure. ***LER 249/04-002***
Palo Verde 1, 2, & 3	2004	Containment sump recirculation potentially inoperable due to pipe voids. ***LER 528/04-009***
Shearon Harris 1	2003	Postulated fire could cause the actuation of certain valves that could result in a loss of the charging pump, RCP seal cooling, loss of RCS inventory, and other conditions. ***LER 400/02-004***
St. Lucie 2	2003	Reactor pressure vessel head leakage due to cracking of control rod drive mechanism nozzles. ***LER 389/03-002***
Crystal River 3 Three Mile Island 1 Surry 1 North Anna 2	2002	Reactor pressure vessel head leakage due to cracking of control rod drive mechanism nozzle(s). ***LER 302/01-004, LER 289/01-002, LER 280/01-003, LER 339/01-003, LER 339/02-001***
Columbia 2	2002	Common-cause failure (CCF) of breakers used in four safety-related systems. ***IR 397/02-05***
Davis-Besse	2002	Cracking of control rod drive mechanism nozzles and reactor pressure vessel head degradation, potential clogging of the emergency sump, and potential degradation of the high-pressure injection pumps. ***LER 346/02-002***
Callaway	2002	Potential common-mode failure of all auxiliary feedwater pumps due to foreign material in the condensate storage tank caused by degradation of the floating bladder. ***LER 483/01-002***
Point Beach 1 & 2	2002	Potential common-mode failure of all auxiliary feedwater (EFW) pumps due to a design deficiency in the EFW pumps' air-operated minimum flow recirculation valves. The valves fail closed on loss of instrument air and this could potentially lead to pump deadhead conditions and a common mode, non-recoverable failure of the EFW pumps. ***LER 266/01-005***
Harris	2002	Potential failure of residual heat removal pump "A" and containment spray pump "A" due to debris in the pumps' suction lines. ***LER 400/01-003***
Oconee 1, 2, & 3 Arkansas 1 Palisades	2001	Reactor pressure vessel head leakage due to cracking of control rod drive mechanism nozzle(s). ***LER 269/00-006, LER 269/02-003, LER 269/03-002, LER 270/01-002, LER 270/02-002, LER 287/01-001 , LER 287/01-003, LER 287/03-001, LER 313/01-002, LER 313/02-003, LER 255/01-002, LER 255/01-004***
Kewaunee	2001	Failure to provide a fixed fire suppression system could result in a postulated fire that propagates and causes the loss of control cables in both safe shutdown trains. ***IR 305/02-06***
Prairie Island 1 & 2	2000	A 1988 change in the backwash system for the cooling water pump drive shaft bearing lubrication water supply system could result in loss of plant cooling water during postulated loss-of-offsite-power conditions. ***LER 282/00-004***
Oconee 1, 2, & 3	2000	Non-seismic 16-inch fire system piping header transited through the auxiliary building and posed a potential flooding problem should the piping rupture during a seismic event. ***IR 269/00-08***
Cook 1 & 2	1999	Postulated high-energy line leaks or breaks in turbine building leading to failure of multiple safety-related equipment. ***LER 315/99-026***

Plant	Year	Event Description
Oconee 1, 2, & 3	1999	Postulated high-energy line leaks or breaks in turbine building leading to failure of safety-related 4 kV switchgear. ***LER 269/99-001***
Cook 2	1998	Postulated high-energy line break in turbine building leading to failure of all component cooling water pumps. ***LER 316/98-005***
Oconee 1, 2, & 3	1998	Incorrect calibration of the borated water storage tank (BWST) level instruments resulted in a situation where the emergency operating procedure (EOP) requirements for BWST-to-reactor building emergency sump transfer would never have been met; operators would be working outside the EOP. ***LER 269/98-004***
Haddam Neck	1996	Potentially inadequate residual heat removal pump net positive suction head following a large- or medium-break loss-of-coolant accident due to design errors. ***LER 213/96-016***
LaSalle 1 & 2	1996	Fouling of the cooling water systems due to concrete sealant injected into the service water tunnel. ***LER 373/96-007***
Wolf Creek	1996	Reactor trip with the loss of one train of emergency service water due to the formation of frazil ice on the circulating water traveling screens with concurrent unavailability of the turbine-driven auxiliary feedwater pump. ***LER 482/96-001***
Wolf Creek	1994	Blowdown of the reactor coolant system to the refueling water storage tank during hot shutdown. ***LER 482/94-013***

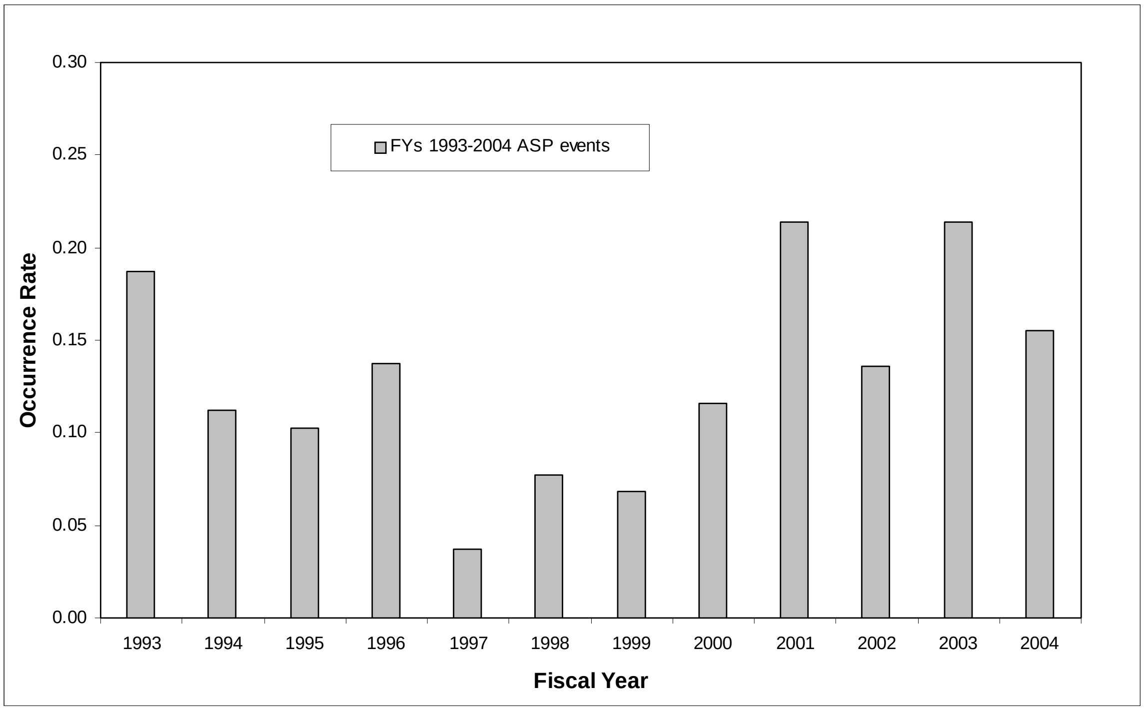

Figure 1: Total Precursors– occurrence rate, by fiscal year. No trend line is shown because no trend was detected that was statistically significant (p-value = 0.1016). FY 2004 results include preliminary data and are subject to change.

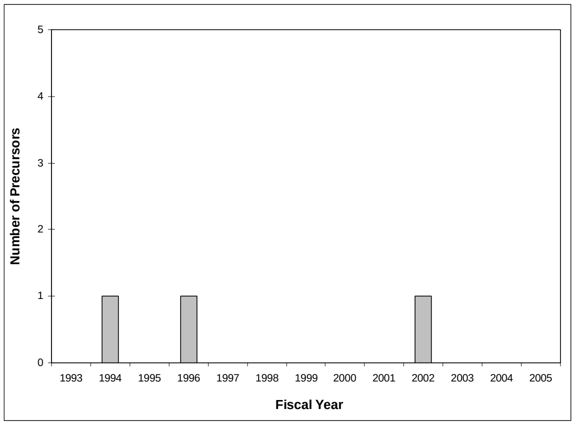

Figure 2a: Precursors in CCDP bin 10^{-3}– number of precursors, by fiscal year. No trend line is shown because no trend is detected that is statistically significant (p-value = 0.5762).

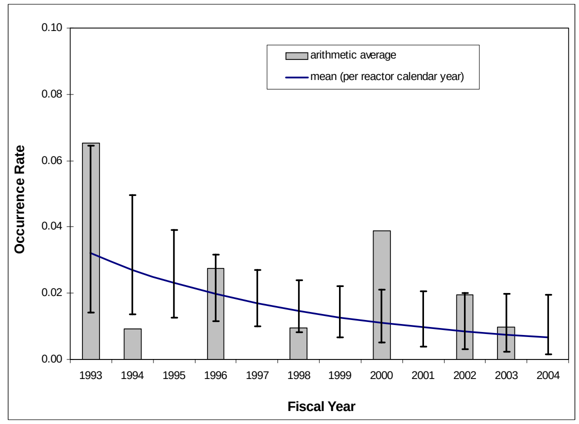

Figure 2b: Precursors in CCDP bin 10^{-4}– occurrence rate, by fiscal year. The decreasing trend is statistically significant (p-value = 0.0291).

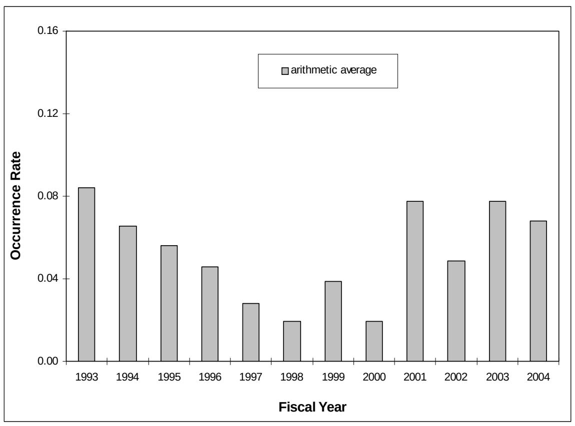

Figure 2c: Precursors in CCDP bin 10^{-5}– occurrence rate, by fiscal year. No trend line is shown because no trend is detected that is statistically significant (p-value = 0.9738).

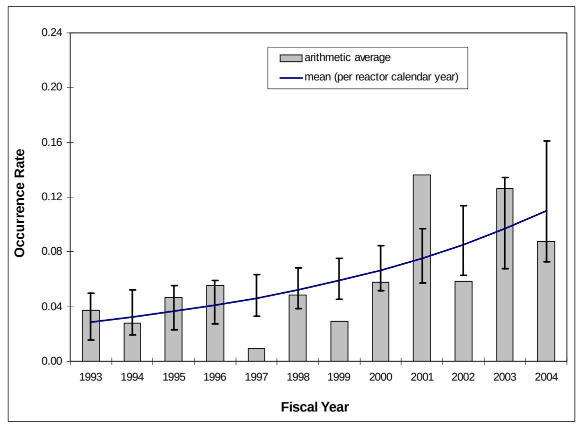

Figure 2d: Precursors in CCDP bin 10^{-6}– occurrence rate, by fiscal year. The increasing trend is statistically significant (p-value = 0.0003).

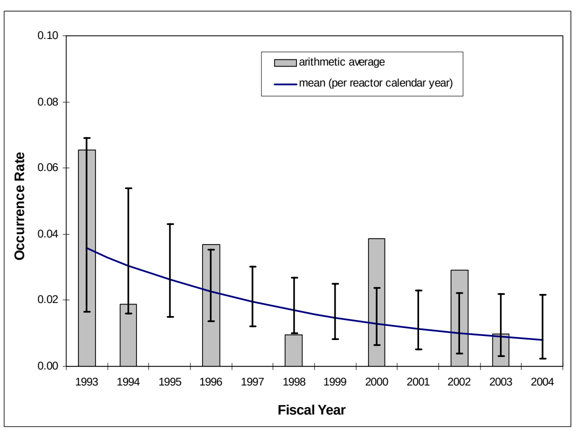

Figure 3: *Important* precursors (CCDP $\$10^{-4}$– occurrence rate, by fiscal year. The decreasing trend is statistically significant (p-value = 0.0255).

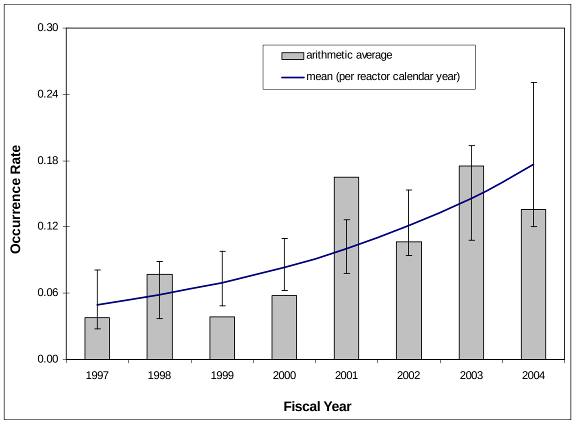

Figure 4a: All precursors during FY 1997–2004 (rebaselined data)– occurrence rate, by fiscal year. The increasing trend is statistically significant (p-value = 0.0002).

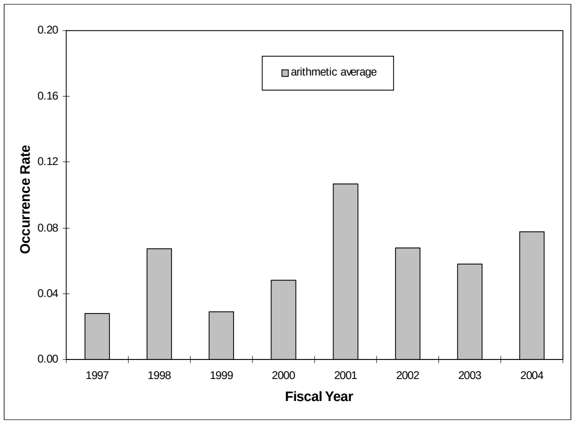

Figure 4b: All precursors during FY 1997–2004 (rebaselined data) excluding all LOOP events and CRDM cracking conditions– occurrence rate, by fiscal year. No trend line is shown because no trend is detected that is statistically significant (p-value = 0.1244)

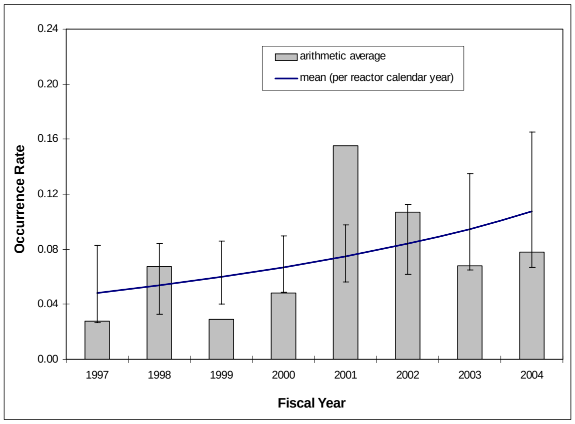

Figure 4c: All precursors during FY 1997–2004 (rebaselined data) excluding all LOOP events– occurrence rate, by fiscal year. The increasing trend is statistically significant (p-value = 0.0419).

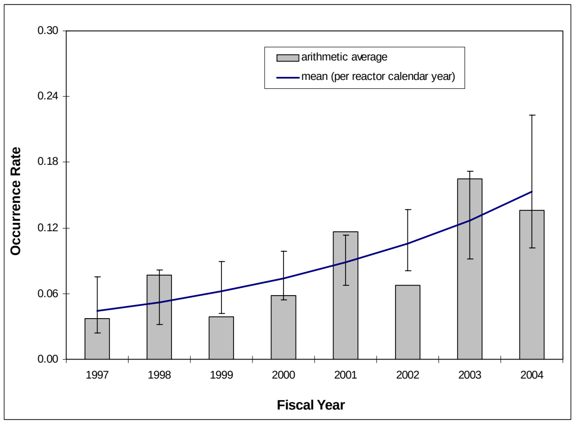

Figure 4d: All precursors during FY 1997–2004 (rebaselined data) excluding CRDM cracking conditions– occurrence rate, by fiscal year. The increasing trend is statistically significant (p-value = 0.0006).

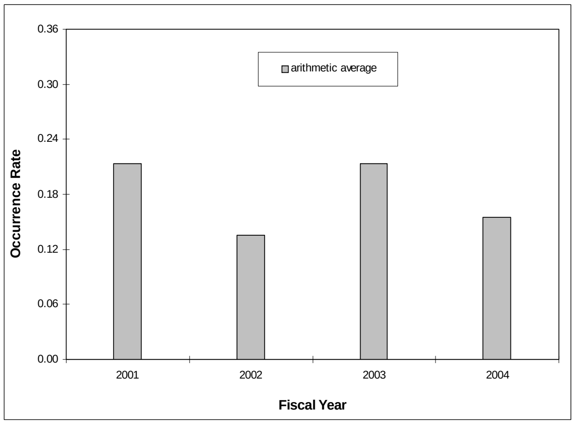

Figure 4e: All precursors during FY 2001–2004– occurrence rate, by fiscal year. No trend line is shown because no trend is detected that is statistically significant (p-value = 0.6031).

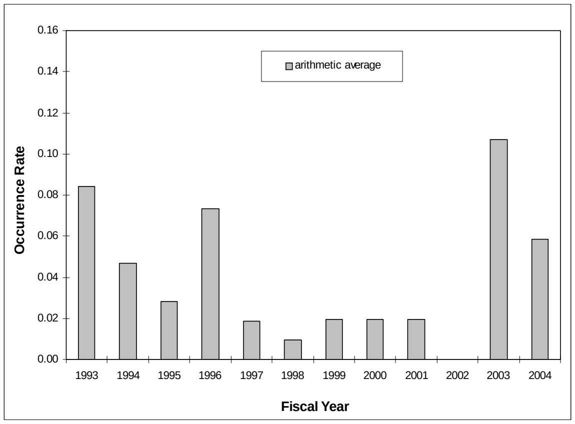

Figure 5: Precursors involving initiating events– occurrence rate, by fiscal year. No trend line is shown because no trend is detected that is statistically significant (p-value = 0.8124).

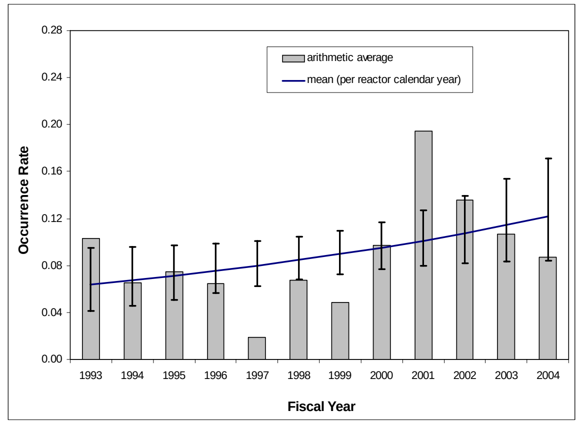

Figure 6: Precursors involving degraded conditions– occurrence rate, by fiscal year. The increasing trend is statistically significant (p-value = 0.0317).

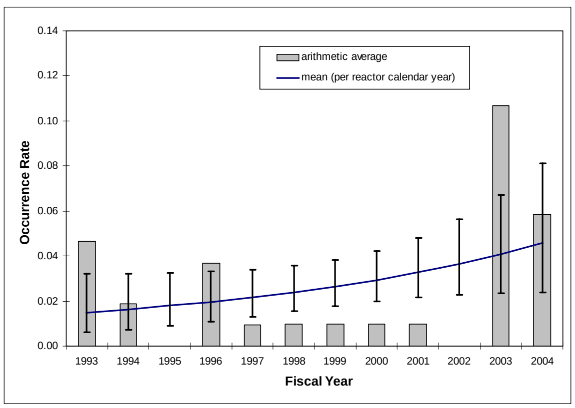

Figure 7: Precursors involving loss of offsite power events– occurrence rate, by fiscal year. The increasing trend is statistically significant (p-value = 0.0405).

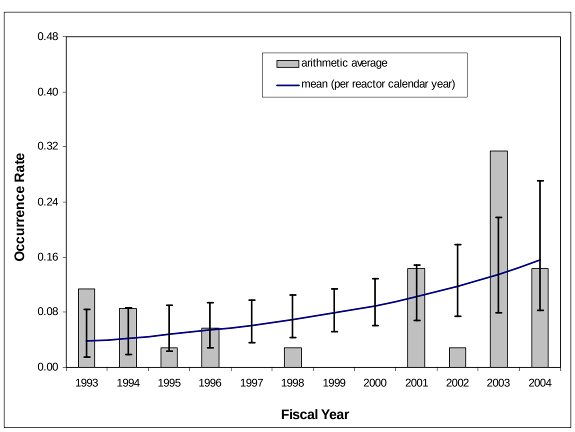

Figure 8: Precursors involving BWRs– occurrence rate, by fiscal year. The increasing trend is statistically significant (p-value = 0.0108).

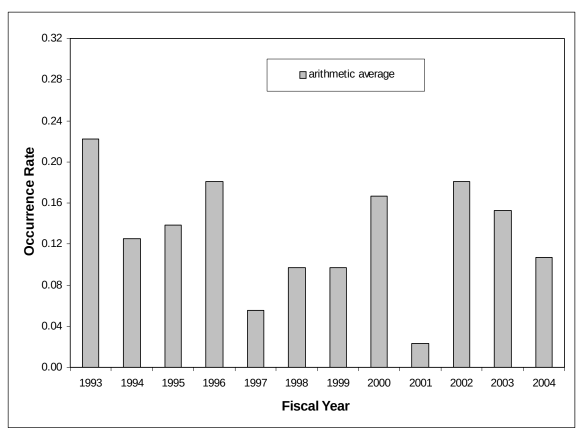

Figure 9: Precursors involving PWRs– occurrence rate, by fiscal year. No trend line is shown because no trend is detected that is statistically significant (p-value = 0.5698).

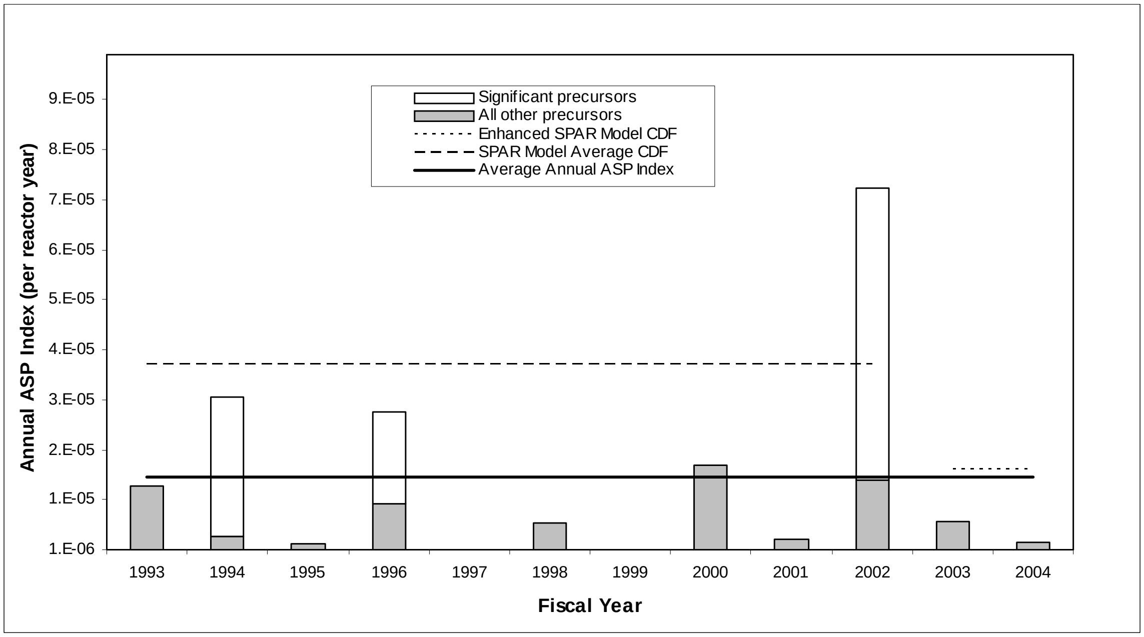

Figure 10: Annual ASP Index– total CCDP and)CDP of all precursors divided by the number of reactor-calendar years in a given year. Fiscal Years with *significant* precursors include 1994 (1), 1996 (1), and 2002 (1). Descriptions of these events are provided in Table 11. For some FY 2003 analyses and all FY 2004 analyses, a new revision of the SPAR models was used. The major changes that occurred in the SPAR models were initiating event frequencies and equipment reliability data updates, revised LOOP recovery curves, and the incorporation of a reactor coolant pump seal LOCA probability calculation package.

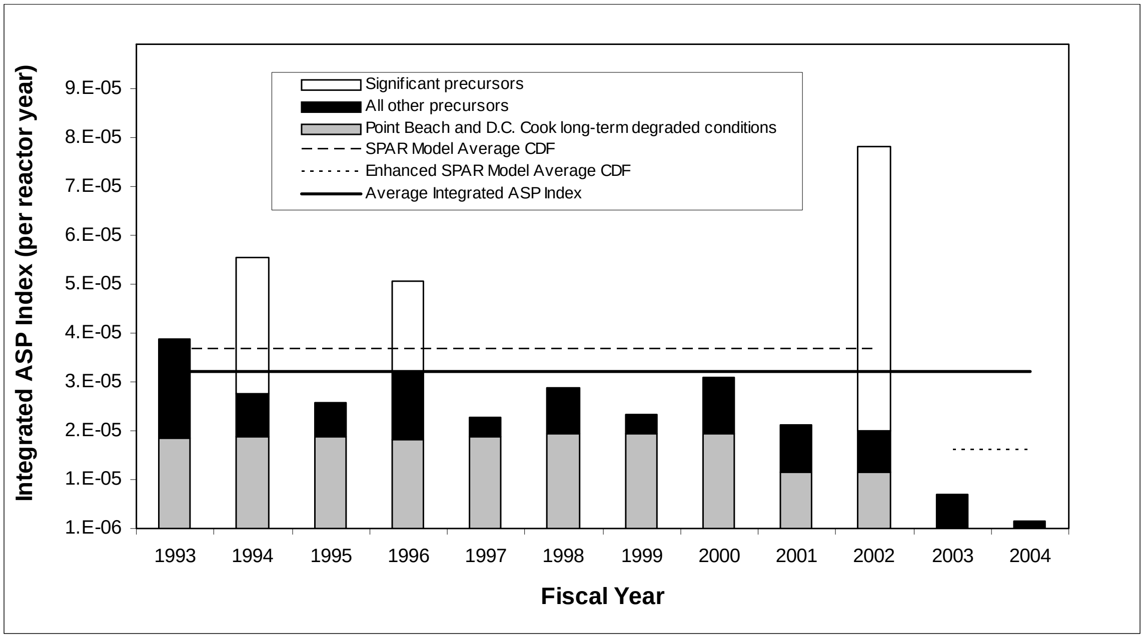

Figure 11: Integrated ASP Index– risk contribution due to precursors, per fiscal year. The risk contribution from the precursors involving degraded conditions is included in all Fiscal Years that the degraded condition existed. The risk contribution from precursors involving initiating events is only included in the FY in which the event occurred. For some FY 2003 analyses and all FY 2004 analyses, a new revision of the SPAR models was used. The major changes that occurred in the SPAR models were initiating event frequencies and equipment reliability data updates, revised LOOP recovery curves, and the incorporation of a reactor coolant pump seal LOCA probability calculation package.